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REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	**§** **§** **§**	**PUBLIC UTILITY COMMISSION OF TEXAS**

NEXTERA ENERGY RESOURCES, LLC'S COMMENTS TO COMMISSIONER'S QUESTIONS

NextEra Energy Resources, LLC ("NextEra") appreciates the opportunity to participate in the Public Utility Commission of Texas's ("Commission") review of the Electric Reliability Council of Texas's ("ERCOT) wholesale electric market design and the related rule-making process. NextEra believes market-based solutions that improve reliability and encourage investment in generation can be adopted from market constructs in other parts of the country in a way that incentivizes the addition of new resources and complements the energy-only market in Texas.

NextEra does not recommend creating two Operating Reserve Demand Curve ("ORDC") pricing regimes or requiring day-ahead participation to qualify for ORDC, as these changes will not drive investment in dispatchable generation or improve reliability. In fact, any change that results in two ORDC price regimes will upend well-established hedging practices, reduce both generation and load's ability to manage risk, and undermine the effectiveness of existing power purchase agreements that are the backbone of over $70 billion of investments in renewable generation in Texas. Additionally, a market design change that requires specific day-ahead activity to qualify for ORDC would remove ERCOT's ability to remedy real-time market supply shortfalls and introduce new market risks to generators.

NextEra is especially concerned that market design changes will be particularly punitive to renewable generators, serve to undermine existing investments, and actually provide a disincentive for new investment, which is clearly contrary to the Commission's objectives. ORDC changes that limit the ability of all generation resources to receive ORDC payments for real time energy supply will ultimately lead to an increase in energy prices as well as a reduction in the existing and future benefits that renewables bring to the state, including revenue-based royalty payments to land owners, property tax revenue, and clean energy jobs.

I. OVERVIEW OF CURRENT ERCOT MARKET DESIGN

The existing ERCOT energy-only market is designed to keep customer costs as low as possible by avoiding both generator capacity payments and compensating generators in return for a "must offer" obligation that requires generators to offer supply in the day-ahead market. As an energy-only market, ERCOT relies on real-time spot energy prices, enhanced by administratively set scarcity premiums via the ORDC during periods of shortage to incentivize investment in new generation. This energy-only market design drives out unnecessary resource-adequacy costs, with the expectation that the market will find the right supply equilibrium on its own, through the combined effect of energy prices and scarcity premiums on investment decisions.

As with any market construct, there are benefits and shortfalls with this design. One of the energy-only market's strong points is that it is very effective at rewarding generators that are available and generating when shortages occur. Additionally, it is equally effective at penalizing generators that do not prioritize operational availability and generators that are not dispatchable because those generators frequently will not capture ORDC scarcity premium and therefore do not benefit from the ORDC construct during the most valuable revenue-generating periods. On the other hand, a shortfall of the energy-only market is that it can have a riskier reliability profile since the market alone dictates the appropriate reserve margin. This type of reliability profile is most precarious during extreme weather patterns, like the February 2021 weather event, because the energy-only design does not impose operational performance mandates or fuel-supply standards to ensure grid reliability. An energy-only market also may fail to effectively translate short-term spot market prices into the longer-term price signals that are required to incentivize new investment. This is problematic because the development of new generation assets requires long-term, capital-intensive investment with multi-year payback periods. If high spot prices do not result in similar long-term price signals, which is currently the case in ERCOT, investors are unable to execute hedges that match the term of their investment risk, thereby preventing new generation from being financed and constructed. For these reasons, energy price signals must be sufficiently dependable over the longer term to support necessary financing requirements. In the absence of such longer-term price signals, an energy-only market may fall short of incentivizing enough generation capacity to maintain grid reliability. Notably, this reliability shortfall cannot be addressed under the current market design by imposing "must offer" requirements on generators in an energy-only market because the market design does not contract for day-ahead commitment obligations, rather, the market only incentivizes voluntary generation commitments through energy price signals.

I. RESPONSE TO QUESTIONS

Question 1: What specific changes, if any, should be made to the Operating Reserve Demand Curve ("ORDC") to drive investment in existing and new dispatchable generation? Please consider ORDC applying only to generators who commit in the day-ahead market ("DAM"). Should that amount of ORDC-based dispatchability be adjusted to specific seasonal reliability needs?

Currently, the ORDC calculation is based on real-time operating reserves (measured by physically responsive capacity, available on-line and off-line capacity) and is applied only to the real-time energy price. This calculation is designed to reflect the probability adjusted value of lost load and incentivize generators to behave in a way that reduces the risk of shed load. Importantly, the ORDC, as currently applied, does not drive investment in existing and new dispatchable generation because the scarcity pricing risk is not flowing through to forward market pricing. The energy-only market with ORDC simply provides a short duration spot price signal that reflects the supply and demand environment at a point in time.

To drive investment in new and existing dispatchable generation, the "energy-only" construct must be altered to address the forward market pricing shortfall that currently acts as a disincentive to generation investment. Investors look to forward pricing curves, not the short-term spot market, to evaluate whether new long-term investment in generation is economically justified. Therefore, to improve grid reliability, the ORDC should be revised in a manner that supports improved forward price signals and contracting opportunities. An extension of the ORDC curve to reflect higher net load variability associated with a system that includes significant intermittent resources could help bridge this gap and support more efficient forward market price signals. In contrast, market design changes that disincentivize real-time energy production by limiting ORDC payments to certain generators will likely exacerbate reliability risks because the primary incentive to produce energy during scarcity periods is removed, and planned investments that anticipated non-discriminatory energy payments under the energy-only market are scaled back or cancelled. For this reason, the ORDC should not be limited only to generators who commit in the day-ahead market as the Commission's question suggests.

In addition, limiting ORDC to generators that participate in the day-ahead market will have negative consequences on the market because it will shrink or altogether eliminate the opportunity for some generators to hedge because hedging requires the opportunity for all generators and load to have exposure to the same commodity price. By discriminating among generators, some generators will no longer be able to hedge with load because the bifurcation of prices makes lower priced generation an ineffective hedge for load when scarcity pricing occurs and ORDC price adders are high. Consequently, load will have fewer counterparties to trade with, and this will result in reduced market liquidity and higher hedging costs.

Changes to the existing market design that cause ORDC scarcity prices to no longer apply uniformly to all real-time energy settlements are not insignificant changes to the energy-only market design. Any market design change that affects the applicability of ORDC scarcity prices affects core market design principles upon which significant capital investments, hedging decisions, and purchased power agreements have been based. Two disparate ORDC pricing regimes could jeopardize existing financings where hedges are in place or where power purchase agreements rely on a single price paradigm. Not only is the generator harmed in these instances, but so are third-party investors who play an essential role in financing investment in the Texas electric grid. If the ability to secure financing for new assets is undermined by proposed ORDC changes, the ultimate effect will be less investment in the Texas electric grid and more reliability challenges. For these reasons, NextEra respectfully recommends the potential effects of changes in generator eligibility for ORDC payments should be carefully evaluated and subject to a separate, more detailed, discussion before moving forward with their adoption.

Finally, if the ORDC scarcity adder is calculated based on real-time operating reserves and used only as an incentive or penalty for generators who cleared in the day-ahead market, ERCOT will lose its ability to impact reserve margins in the real-time. This will occur because the above referenced calculation incorrectly assumes system conditions do not change between the day-ahead market and the real-time market. For example, if real-time load is higher than forecasted or a large generator that committed in the day-ahead market unexpectedly trips, a shortage of operating reserves in the real-time may occur and the ORDC will be powerless to remedy this situation. This, in turn, will result in indiscriminate load shed. To avoid this indiscriminate load shed, ERCOT would have to procure enough excess reserves in the day-ahead market to address any unforeseen market conditions. This excess procurement effectively functions as daily insurance to protect against all possible unexpected circumstances, resulting in an unnecessary surplus of capacity that significantly increases the costs to operate the system. To avoid such a result, the Commission should consider implementing market-based demand response mechanisms that encourage voluntary price sensitive load reduction and other incentives that promote ramping of uncommitted generators.

Question 2: Should ERCOT require all generation resources to offer a minimum commitment in the day-ahead market as a precondition for participating in the energy market? a. If so, how should that minimum commitment be determined? b. How should that commitment be enforced?

Market design changes that increase uncompensated risks end up reducing the amount of generation in the market and increasing ERCOT's reliability challenges. Imposing additional burdens on resources such as a minimum commitment in the day-ahead market adds uncompensated exposure to unit trips and real-time energy buy-backs that will only drive supply out of the market and discourage future investment. It is also important to understand that, in addition to performance risk, the ability to accurately predict the market price and availability of fuel by the applicable day-ahead submission deadline can be challenging in certain seasons. Stated differently, for a marginal resource, there is no incremental incentive built into the day-ahead clearing mechanism that generates revenues sufficient to justify the risk of a day-ahead commitment. This must be changed if generators are required to participate in the day-ahead market as a pre-condition of participating in the energy market.

Generation owners have a wide array of risk appetites and any day-ahead offer requirement must provide for flexibility in the volume and/or offer price to accommodate the risk tolerance of each generator. Intermittent resources must be given an even greater level of flexibility given their reliance on a fuel source whose availability is outside of their control.

Question 3: What new ancillary service products or reliability services or changes to existing ancillary service products or reliability services should be developed or made to ensure reliability under a variety of extreme conditions? Please articulate specific standards of reliability along with any suggested AS products. How should the costs of these new ancillary services be allocated.

Any reliable electricity system requires sufficient resources to satisfy all critical loads in real time at an acceptable cost. Real time reliability is the ultimate metric of success. Load is always the ultimate customer who benefits from an effective market and pays for the total suite of reliability services.

However, because of the capital-intensive, long-term resources that are required for the electricity system, real time reliability depends on considerable forward-looking planning and investment activity. In all electricity markets, whether this is called capacity, resource adequacy, sufficiency or resilience, it is all about incentivizing prudent investments in a diverse fleet of resources to provide the necessary energy and reliability services for the future "real time" situations. This must be a thoughtful, forward-looking process that is constantly being informed by new information, events, technologies and grid transformation more broadly.

This forward-looking planning process must occur in every electricity system. As NextEra operates over 26 GW of generation in all electricity markets in North America, we know that there are a number of ways to accomplish the long-term planning process. All methods fundamentally depend on loads arranging and paying for resources to provide the range of energy and reliability services that are needed. All methods fundamentally depend on incentivizing generators to make long-term investments, while being compensated to assume reasonable risk in return for a commitment to perform along with penalties for non-performance. Whether this is done through regulated planning, long-term contracts or market products such as a capacity or resource adequacy market, all methods depend on some measure of performance by the resources—different resources will most effectively provide different attributes to the system and are best used as a portfolio that contributes to the future reliability, economics, resilience, and sustainability that the loads desire.

Solely relying on real time scarcity pricing in the ERCOT market is proving to be insufficient to translate into the long-term forward price signals that are necessary for planning and investment. Texas' commitment to an energy-only market has provided significant cost benefits as it has led to a significant reduction in energy prices; however, the market price signals, even at the $9,000 cap, have not been as successful as anticipated at encouraging or incentivizing new investments. NextEra believes that this forward price signal could be provided by having ERCOT define and augment its existing market with a future reliability obligation on loads (or procured by ERCOT for the loads).

Question 4: Is available residential demand response adequately captured by existing retail electric provider ("REP") programs? Do opportunities exist for enhanced residential load response?

ERCOT's annual demand response survey accurately captures the capability of existing REP demand response programs. Opportunities to leverage smart meter capabilities that consumers have already paid for should be investigated in order to potentially expand the range of REP demand response offerings. In particular, ERCOT and the Commission should re-evaluate whether home area network ("HAN") functionality associated with smart meters should be restored so the HAN functionality can be leveraged to provide consumers with more attractive demand response products that ERCOT can also rely on as high probability, command and control, interruptible loads.

Question 5: How can ERCOT's emergency response service program be modified to provide additional reliability benefits? What changes would need to be made to Commission rules and ERCOT market rules and systems to implement these program changes?

Not addressed.

Question 6: How can the current market design be altered (e.g., by implementing new products) to provide tools to improve the ability to manage inertia, voltage support, or frequency?

No market design alterations are necessary beyond the current tools, products, and practices that ERCOT currently uses to manage inertia, voltage support, and frequency. ERCOT has long been a global leader in using market products, operational tools, interconnection requirements, and standards to ensure sufficient inertia, voltage support, and frequency support. For example, ERCOT implemented a requirement that all wind and solar resources provide primary frequency response in 2012, becoming the first system operator in the United States to do so. This requirement was further enhanced and applied uniformly to all generators (except nuclear) with the North American Electric Reliability Corporation ("NERC") regional BAL-001-TRE standard in 2014.

ERCOT has also been a leader in understanding the relationship between system inertia and responsive reserve ancillary services. In this regard, ERCOT implemented real-time tools to monitor system inertia in their control room in 2016—carefully monitoring and operating to ensure that the system has sufficient inertia to operate reliably with existing frequency control practices. ERCOT has also demonstrated the value and utility of relying on faster and more accurate sources of response reserve service. ERCOT's actions in this regard have proven that faster and more accurate frequency response (such as the fast frequency response from wind generators, storage resources and certain load resources) are significantly more effective than the primary frequency response of conventional resources in arresting frequency change following a large generator trip in ERCOT.

Regarding voltage support, ERCOT already successfully coordinates with transmission service providers to establish voltage profiles across the ERCOT region. ERCOT's outreach to transmission service providers and qualified scheduling entities ensures that established voltage levels are maintained. Finally, ERCOT obtains additional voltage support ancillary service from both conventional and renewable generation resources, including wind power plants, through its Voltage Support Service.

II. CONCLUSION

In summary, consumers in Texas have benefited from low electricity bills resulting from a diverse generation mix, which includes low-cost wind and solar. In addition to helping the energy market achieve affordable energy prices, renewables provide a multitude of benefits for rural Texas communities including royalty payments, property tax revenue, and clean energy jobs. Implementation of any market design change which are targeted at renewables, such as bifurcated ORDC payments or required day-ahead bidding, undermine existing renewables investments, deter future investment, adversely impact the numerous benefits renewables bring to the state, and further jeopardize reliability in ERCOT. Additionally, these changes will not address ERCOT's long-term reliability needs because they don't address the root cause of the problems the energy-only market is experiencing. To remedy the problems that exist in the current market design, an additional streamlined and discrete revenue stream is required for dispatchable resources or resources that bid in the day-ahead market. NextEra recommends the Commission focus on incorporating existing solutions from other markets to address this need.

NextEra reiterates its appreciation of the opportunity to offer these comments and looks forward to continuing to work collaboratively with the Commission and other stakeholders to investigate market design changes that will provide a more resilient and reliable electric grid.

Respectfully submitted

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